Submergible Pumping Applied to Wells With Multiphase Flow

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INTRODUCTION

Among the artificial lift systems presently used in oil wells, the one called electrical submergible pumping presents special characteristics which give it advantages over the other systems for producing wells under certain conditions. Figure 1 shows the way in which a submergible pumping unit is commonly installed. The electric motor is in the lower part of the string and receives, through an electric cable, energy from a source on the surface. The pump hangs from the bottom end of the production string and discharges into it the pumped fluids. The pump gets its impulse from the motor through a connecting shaft located inside the protector or seal section. If required, a bottomhole gas separator can be installed at the pump intake. All these components are firmly assembled as shown in Fig. 1.

Two aspects that require very special consideration, in the event that an electrical submergible pump is going to be installed in a producing well, are the determination of the proper pump setting depth and the calculation of the pressure head which the pump must supply to the well fluids, in order to have the desired surface production rate at the required pressure.

At present, most of the installations have been calculated assuming that: (1) the pump must be set below the working fluid level at a distance that insures uninterrupted feeding, taking precautions for possible variations in well conditions;[1] and (2) the flow in the vertical string is of liquid phase in its entirety, calculating the corresponding friction losses with Hazen-Williams formula.[2,3]

These assumptions are valid when one is producing from wells having high water-oil ratios and small formation gas volumes. However, in cases where oil and formation gas constitute a considerable part of the fluids to be produced, it is necessary to take into consideration the effects of the gas which comes out of solution within the flow string as pressure decreases. The reduction in the density of the mixture at pressures lower than bubble-point pressure is considerable in these cases and, as Smith[4] states, taking this factor into account can lead to a 50 per cent reduction in the number of pump stages and motor power requirements, as compared to values obtained with the assumption normally made.

The procedure presented here performs the corresponding calculations considering vertical multiphase flow in the production string, thus arriving at values that are really representative of the operating condition of the well, and making possible an optimum pumping equipment selection.

DESCRIPTION OF THE METHOD

One of the factors that more unfavorably affects the performance curves of a centrifugal pump, is the presence of free gas entrained in the handled liquid. In general, centrifugal pumps will operate according to their nominal performance curves only when the free gas-liquid ratios are small. Performance curves are understood to be the measured relationships between the flow rate delivered by the pump and the pressure developed, the efficiency of the pump, and the power requirements. The allowable free gas-liquid ratios will depend upon the type and design of each pump. For larger ratios, pump performance will depart noticeably from what would be expected according to the nominal performance curves, that is, the ones given by the manufacturer. Pump performance will be impaired even more when cavitation effects, due to the gas within the well fluid, begin to be felt.

Even though this behavior is well-known, there is no analytical method available to quantify the deviations experienced by performance curves, when working with free gas excess. Therefore, the criterion adopted to determine the pump setting depth was that the free gas which goes through the pump should

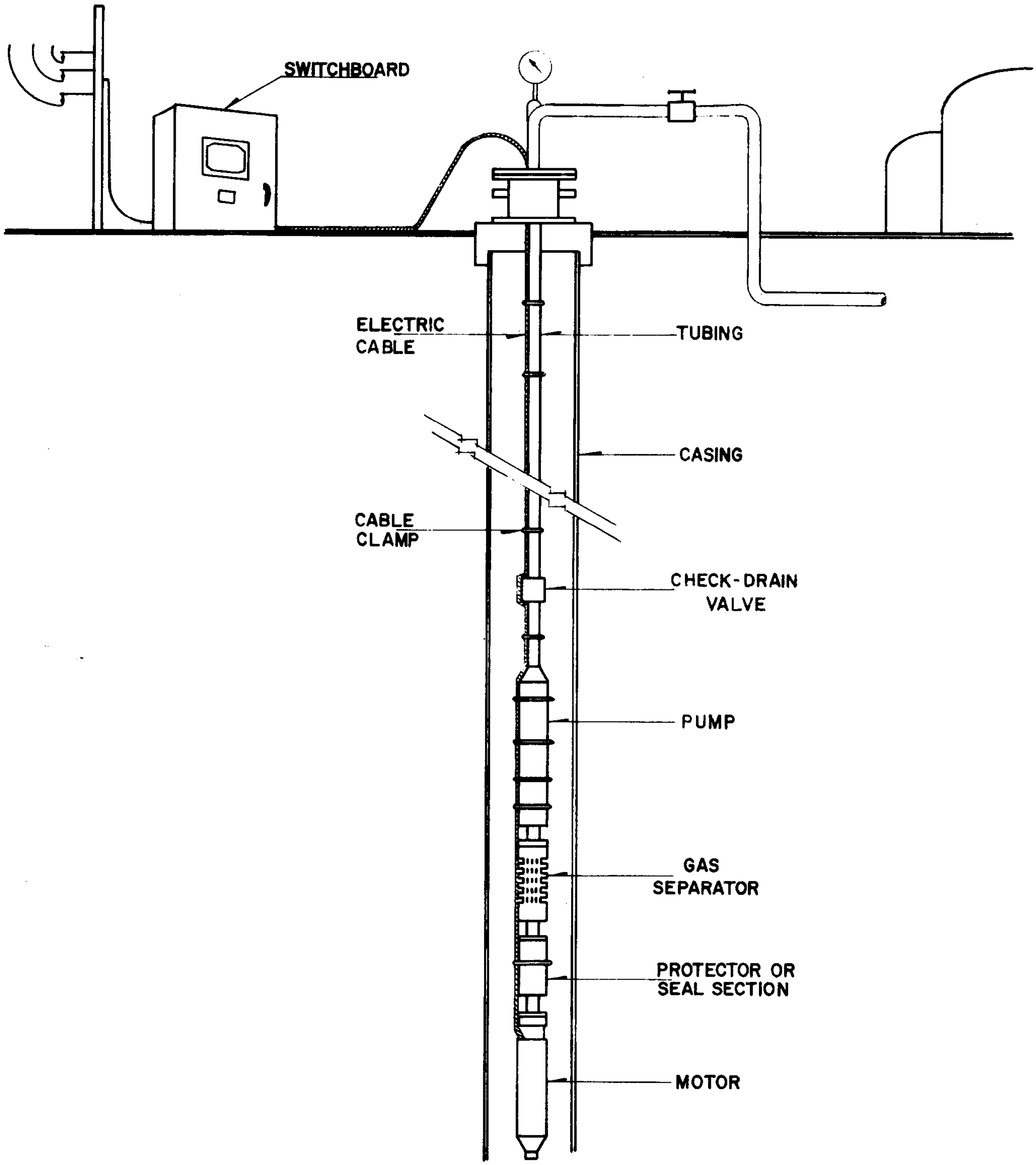

FIGURE 1

TYPICAL INSTALLATION OF AN ELECTRICAL SUBMERGIBLE CENTRIFUGAL PUMP IN AN OIL PRODUCING WELL

not alter noticeably the nominal performance curves. Since most centrifugal pumps used in oil wells are of the vertical mixed flow type, [5,6] the allowable free gas-liquid ratio was taken as 10 per cent, as recommended by Hicks.[7] Nevertheless, this does not represent a limitation to the applicability of the procedure, because the allowable free gas-liquid ratio enters as a variable in the computer program and therefore, if convenient, the value of the ratio that is considered adequate for the type of pump to be used can be supplied as a datum.

The procedure presented here also takes into account the fact that the pump can have a bottomhole gas separator, which will prevent part of the free gas that exists at the pump setting depth from entering the pump. For calculation purposes, it was considered that bottomhole separators work with an efficiency of 85 per cent,[8] but inasmuch as this value can change according to well fluid and pump operating conditions, an efficiency variable has been included in the computer program; therefore, it will suffice to supply the appropriate value of separation efficiency and the calculations will be carried out accordingly.

Considering all of the aforementioned, a calculation sequence was developed using the following pattern:

1. Starting with the static bottomhole pressure, total flow rate and total productivity index, the flowing bottomhole pressure is calculated:

$$P_{wf} = P_{ws} - \frac{q_t}{J_t} \qquad (1)^*$$

2. Following the procedure proposed by Poettmann and Carpenter,[9] and beginning with the flowing bottomhole pressure of the middle perforations, the pressure traverse in the vertical string is determined. The result of these calculations is illustrated by curve A in Fig. 2. As the traverse is being calculated, the volume occupied by the free gas at flowing conditions per cubic meter of oil at standard conditions is determined in each interval:

$$R_F = (R - R_s)\,\frac{p_a\,\bar{T}\,\tilde{z}}{\bar{p}\;T_a} \qquad (2)$$

The resulting figure is diminished by 85 per cent, an amount which represents the volume of gas deviated to the annulus by the separator. The remainder is compared with the volume occupied by the liquids at the same conditions:

$$F_{Lo} = F_{wo}\,B_w + B_o \qquad (3)$$

At the point where the free gas-liquid ratio at flowing conditions is equal to 0.1, the maximum allowable ratio in the pump, the calculation of the pressure traverse is interrupted and the depth reached at this point will be the pump setting depth, D_B. This point is marked with the letter M in Fig. 2.

3. Next, one must determine the pressure head which the pump must supply to the well fluids in order to reach the desired flow rate. To do this, a second pressure traverse is calculated using the same method as in step 1 and employing a gas-oil ratio equal to the one obtained from the formation, minus the amount corresponding to the free gas deviated to the annulus. This traverse is represented by curve B in Fig. 2. In each interval of the new traverse, a comparison is made between its depth and the pump setting depth already calcluated. The process stops when these two depths are equal, point N in Fig. 2. The difference in pressure between the two traverses, distance MN in Fig. 2, represents the increase in pressure required to operate the well under the given conditions.

Once the optimum setting depth and pressure head of the pump have been determined, the various components that constitute the electrical submergible pumping unit are selected. This selection is made according to the steps described below.[1,2,3,10]

4. A pump whose efficiency curve has its maximum at, or very near, the desired flow rate is chosen. The pump must also be capable of being run in the well casing. Typical centrifugal pump performance curves are shown in Fig. 3.

5. The number of pump stages is determined dividing the required pressure head by the pressure head per stage that the selected type of pump is capable of supplying, at the desired flow rate. The pressure head per stage is read with curve 1 in Fig. 3.

$$\text{No. of stages} = \frac{10\,\Delta p}{h} \qquad (4)$$

6. The power of the motor required to drive the pump is determined by multiplying the power required to drive one stage (curve 2 in

*Nomenclature at the end of the paper.

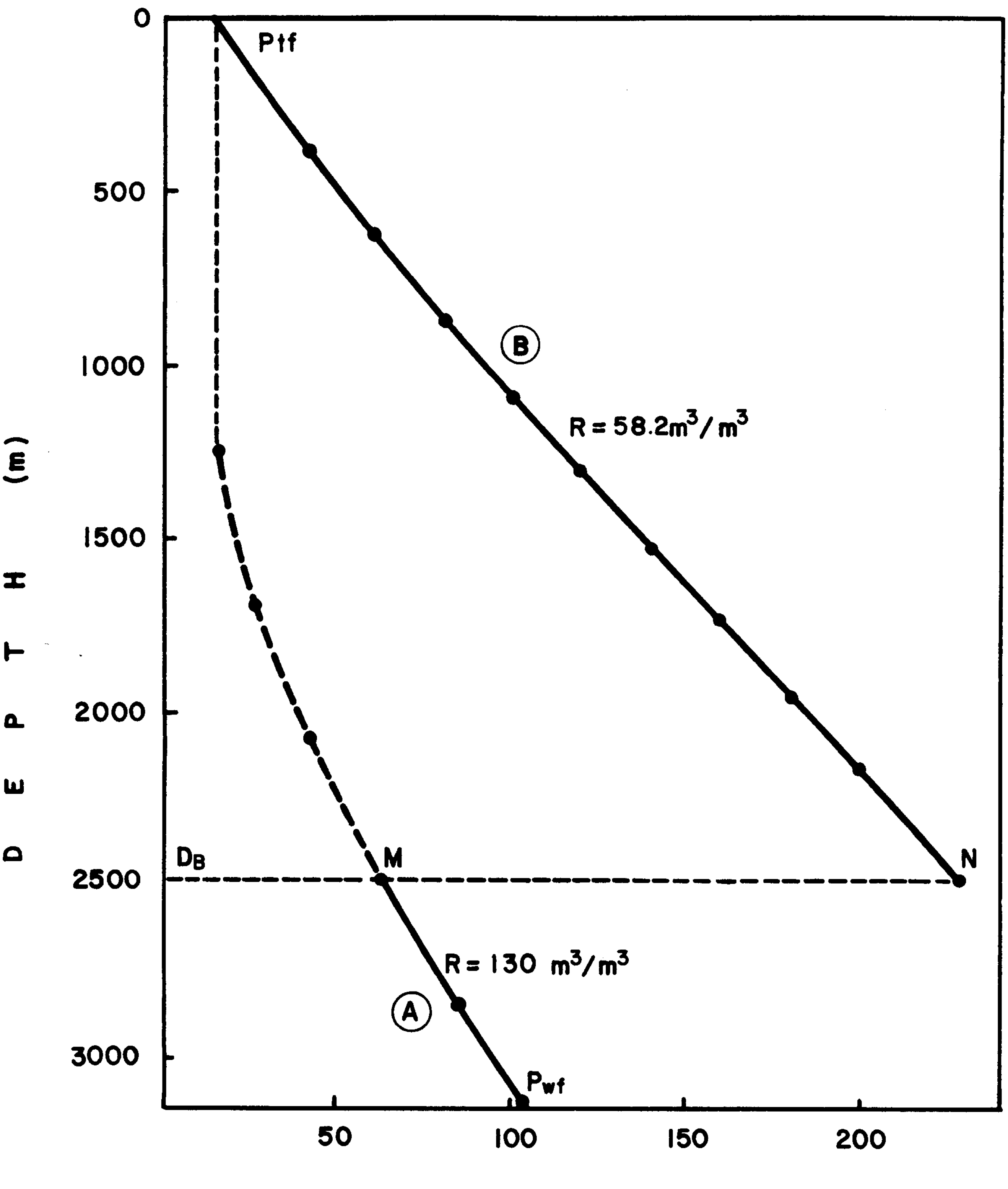

FIGURE 2

PUMP SETTING DEPTH AND
PRESSURE HEAD DETERMINATION

Fig. 3) by the number of the stages of the pump:

$$HP_t = HP_e \times \text{No. of stages.} \qquad (5)$$

7. The motor is selected taking into account that its outside diameter must be such that the pumping unit can be run into the well. The motor voltage will depend as much on the voltages in which that particular size of motor is manufactured, as on the voltage available at the surface and the clearance between the pumping unit and the casing. This clearance will define the maximum cable size which may be used for the electric cable. At the same time, the electric cable must comply with the condition that the voltage drop through it must not exceed 20 per cent of the motor voltage.[10]

In view of the foregoing facts, and in order to facilitate the corresponding calculations, equipment manufacturers have devised charts that can be used advantageously to quickly determine motor voltage, electric cable size and voltage drop through the cable.[2,3]

In case the motor voltage differs considerably from the voltage available at the surface, a transformer which supplies the required operating voltage must be installed, its capacity being:

$$KVA = \frac{\sqrt{3} \times V \times I}{1000} \qquad (6)$$

where the operating voltage V, equals the motor voltage plus the voltage drop through the electric cable.

8. Next, a protector or seal section is selected with a diameter adequate to the rest of the installation, in order to prevent the well fluids from entering the motor. Also, a bottomhole gas separator is chosen in order to facilitate free gas elimination at the pump suction.

9. The next step consists in determining the type of switchboard that needs to be installed on the surface. This switchboard should be designed to handle the operating voltage. Its horsepower capacity must at least be equal to that of the motor. The type of information and control desired on the surface will determine the type of equipment to be installed in the switchboard. This equipment can be simple: disconnect switch, starter button and overload protection. Or it can be very elaborate: automatic timers for intermittent operation, undercurrent shutdown relay, recording ammeter, etc.

10. A wellhead of special design is chosen, which must provide a suitable passage for the electric cable and be adequate for the tubing and casing installed in the well. Also, metallic cable bands should be selected, in proper size and number, to fasten the electric cable to the tubing, pump and protector. It is recommended that cable bands be spaced at five-meter intervals on the tubing and that 25 bands be used to clamp the cable to the pump and protector.

11. Finally, one must select a series of accessory equipment to facilitate the transportation, installation and operation of the unit, such as cable reels, check and drain valves, metallic shipping boxes for pump and motor, etc.

COMPUTER PROGRAM

The procedure was programmed to be processed with an IBM-1130 electronic computer. The convenience of having a computer program available is evident, since the calculations involve the determination of pressure traverses in the vertical strings, with simultaneous flow of oil, water and gas.

The major advantage in working the procedure with a computer is that one is able to analyze quickly and easily a certain well under changing conditions of flow rate, water content, productivity index, tubing diameter, etc., all of which are involved in a better planning of production operations.

The corresponding flow diagram, shown in Fig. 4, might be useful to better understand the mechanics of the procedure.

The input data to the program are:

1. Bottomhole gas separator efficiency, (per cent)
2. Free gas-liquid ratio allowable in the pump, (m^3/m^3)
3. Reservoir name
4. Oil specific gravity
5. Gas specific gravity
6. Water specific gravity
7. Water formation volume factor
8. Flowing wellhead temperature, (°C)
9. Bottomhole temperature, (°C)
10. Depth at which (9) was measured, (m)
11. Atmospheric temperature (°C)
12. Atmospheric pressure, (kg/cm^2)
13. Data from oil PVT analysis

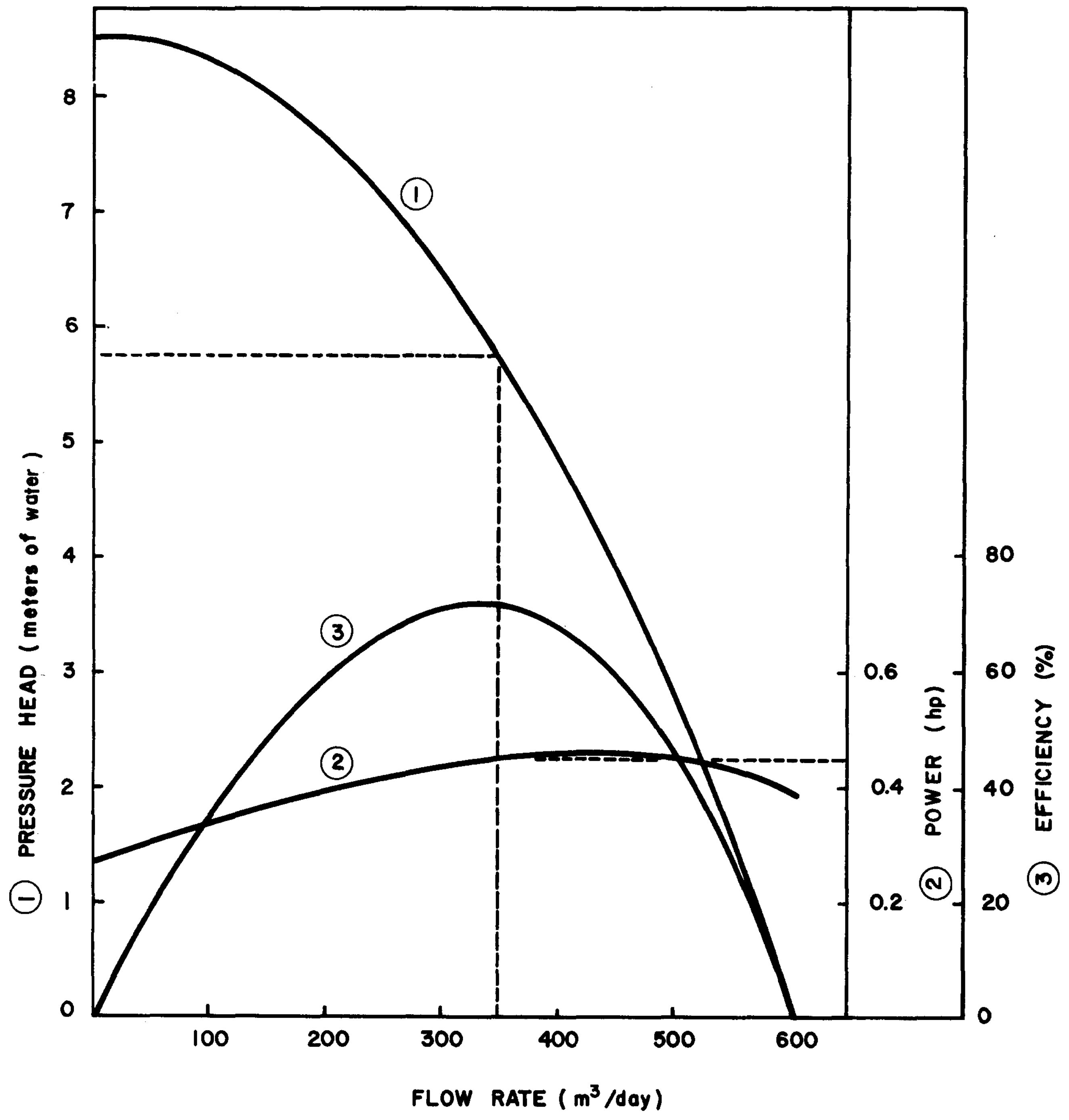

FIGURE 3

CENTRIFUGAL PUMP PERFORMANCE CURVES
ONE STAGE VALUES

14. Well name
15. Depth to the middle of the producing interval, (m)
16. Static bottomhole pressure, (kg/cm^2)
17. Total flow rate, (m^3/day)
18. Total productivity index, (m^3 liq/day/kg/cm^2)
19. Water-liquid ratio
20. Producing gas-oil ratio, (m^3/m^3)
21. Flow conduit to the surface
22. Tubing diameter, (in.)
23. Casing inside diameter, (in.)
24. Required flowing wellhead pressure, (kg/cm^2)

In relation to these data, the following explanations are pertinent: If the values of items 1 and 2 are unknown, calculations will be made considering values of 85 per cent and 0.1 respectively, in accordance with what was said earlier in this paper; if it is desired to make calculations for several wells of different reservoirs, then items 3 to 13 can be given only once for each reservoir, provided item 14 indicates the reservoir each well belongs to; item 13 must include equations for the oil formation volume factor and for the solution gas-oil ratio as functions of pressure.

In item 21 it must be specified whether the flow, from the pump discharge to the surface, goes through the tubing or whether it goes through the annulus between tubing and casing; the computer program was elaborated foreseeing these two possibilities. If the flow goes through the tubing, then the inside diameter of the tubing must be given in item 22. If the flow goes through the annulus, the value given in item 22 must be that of the outside diameter of the tubing.

The following remarks can be made in relation to the results which can be obtained from the computer. Normally, the computer will make the necessary calculations to determine traverses A and B of Fig. 2, and at the end it will print the setting depth and the pressure head required for the pump. However, if a computer switch is previously actuated, then it will also give points on the pressure traverses, with a 5 kg/cm^2 spacing. Also, actuating a second switch, the continuation of traverse A can be obtained, and from it the theoretical working fluid level depth in the annulus. The results obtained from the actuation of the second switch are illustrated in Fig. 2, dashed section of curve A.

APPLICATION

A numerical example showing the results obtained with the computer is given. The corresponding computer switches were actuated in order to obtain the values of pressure and depth with which traverses A and B in Fig. 2 were constructed.

DATA

Date	2/16/70
Well No.	1
Reservoir	Test
Producing interval middle depth	3,140 meters
Static bottomhole pressure	250 kg/cm^2
Total flow rate	350 m^3/day
Total productivity index	2.375 m^{3}liq/day/kg/cm^2
Water-liquid ratio	0.500 m^3/m^3
Producing gas-oil ratio	130 m^3/m^3
Flow through tubing	
Tubing inside diameter	2.441 in.
Casing inside diameter	5.791 in.
Required flowing wellhead pressure	15 kg/cm^2

Fluid properties were taken from well San Andres 86 P.V.T. analysis.[11]

RESULTS

Pump setting depth	2475.67 meters
Suction pressure	61.97 kg/cm^2
Discharge pressure	227.50 kg/cm^2
Required pressure head	165.53 kg/cm^2
Flowing bottomhole pressure	103.00 kg/cm^2

Traverse A was calculated with a gas-oil ratio of 130 m^3/m^3 and traverse B with one of 58.2 m^3/m^3, the gas separator accounting for the difference.

Of all the available pumps capable of being run in wells with 6-⅝ in. OD, 28 lb/ft casing,[2,3] the one whose performance curves are shown in Fig. 3 was chosen because it operates with maximum efficiency for the given flow rate of 350 m^3/day.

The number of pump stages was calculated with equation (4):

$$\text{No. of stages} = \frac{10 \times 165.53}{5.75} = 287.88$$

Thus, the pump will have 288 stages.

The motor power is obtained substituting in equation (5):

$$HP_t = 0.437 \times 288 = 125.86 \text{ hp}$$

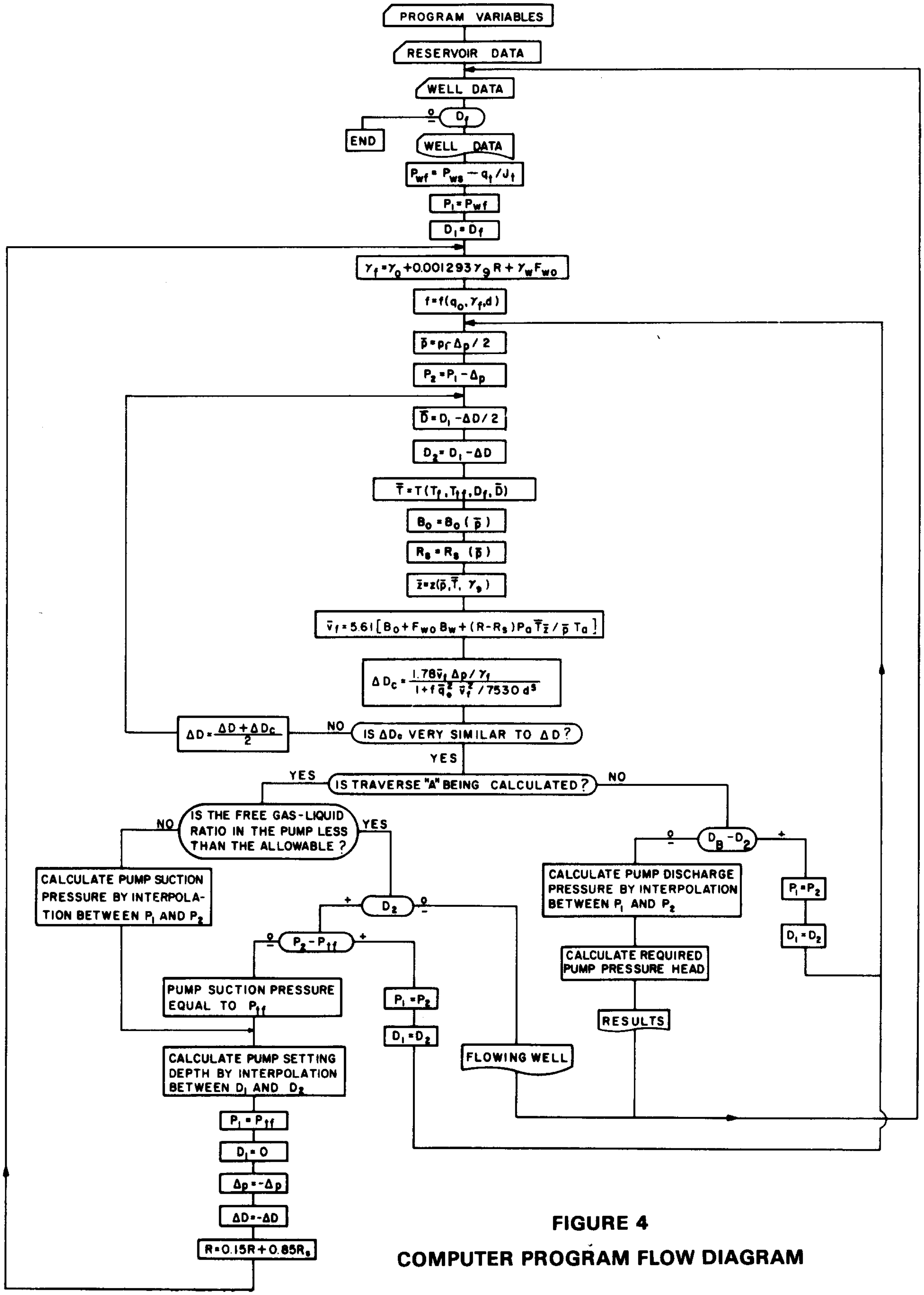

FIGURE 4

COMPUTER PROGRAM FLOW DIAGRAM

As 120-hp motors are standard, one of them will be right for the pumping installation, since its outside diameter is 4-½ in. Furthermore, if a voltage of 1140 volts is chosen for the motor, the current will be 69 amp. With these values it is possible to choose a size No. 2 electric cable, having a voltage drop of 7.87 volts per 100 meters of cable, for a current of 69 amp. If it is assumed that 30 additional meters of cable will be used for surface connections, then the total drop in the cable will be of:

$$7.87 \; \frac{(2475.67 + 30)}{100} = 197.20 \text{ volts.}$$

which is within the allowable limits. On the other hand, the outside diameter of size No. 2 cable is such that its running with the pumping unit does not represent a problem. Nevertheless, a length of flat cable should be chosen with such a thickness that it can easily go between the pump-separator-protector assembly and the casing to reach the motor. In this case, the suitable gas separator and protector are 1.53 meters in length each. Since the pump measures approximately 8.05 meters, then 12 meters of size No. 4 flat cable will suffice.

The surface operating voltage is:

$$V = 1140 + 197.20 = 1137.20 \text{ volts}$$

and the capacity of the transformer; in the event that one is needed, would be, by equation (6):

$$KVA = \frac{\sqrt{3} \times 1337.20 \times 69}{1000} = 159.81$$

that is, a 150 KVA transformer would be adequate.

A switchboard designed for 1500 volts and 150 hp would be enough for the installation, as well as a type RC tubing head with a 300, 000-lb maximum load capacity. The rest of the equipment is selected in accordance with well conditions, results from calculations already made, and the control and information desired in relation to the pumping unit operation.

CONCLUSIONS

The procedure presented can be advantageously used to determine more representative values of the factors involved in electrical submergible pumping installation calculations, when working with wells of low water-oil ratios and large formation gas production.

The procedure is complemented with the mechanization of operations. This supplies advantages which become obvious when it is considered that the complete calculation of the required pressure head and setting depth of the pump requires 3 or 4 hours work from a well-trained person working with a desk calculator; these same calculations require about 30 seconds with a computer.

The ideas presented can be further applied after more studies are made showing the way in which free gas affects centrifugal pump performance curves, so that installation calculations are not restricted by nominal performance curves. It is also considered advisable to investigate whether the temperature at the bottom end of the unit exceeds or does not exceed the equipment allowable limits, as a result of energy dissipation in the form of heat from the electrical system of the unit in operation.

NOMENCLATURE

B_o	Oil formation volume factor
B_w	Water formation volume factor
d	Flow string diameter, (in.)
D_B	Pump setting depth, (m)
D_f	Depth to the middle of the producing formation, (m)
D_I	Initial point depth for each interval, (m)
D_2	Final point depth for each interval, (m)
$\overline{D}$	Mean depth for each interval, (m)
ΔD	Assumed length for each interval, (m)
ΔD_c	Calculated length for each interval, (m)
f	Friction factor
F_{Lo}	Volume occupied by the liquids at flowing conditions, per cubic meter of oil at standard conditions
F_{wo}	Water-oil ratio
h	Pressure head developed per stage, stage, (meters of water column)
HP_e	Power required per pump stage, (hp)
HP_t	Total power required for the pump, (hp)
I	Electric current, (amp.)
J_t	Total productivity index, (m^3liq/day/kg/cm^2)

KVA	Electric power, (kilovolt-amp.)
p_a	Atmospheric pressure, (kg/cm^2)
p_{tf}	Flowing wellhead pressure (kg/cm^2)
p_{wf}	Flowing bottomhole pressure, (kg/cm^2)
p_{ws}	Static bottomhole pressure, (kg/cm^2)
p_1	Initial point pressure for each interval, (kg/cm^2)
p_2	Final point pressure for each interval, (kg/cm^2)
$\bar{p}$	Mean pressure for each interval, (kg/cm^2)
Δp	Pressure variation in each interval, (kg/cm^2)
q_o	Oil flow rate, (m^2/day)
q_t	Total flow rate, (m^3/day)
R	Producing gas-oil ratio
R_F	Volume occupied by free gas at flowing conditions, per cubic meter of oil at standard condidions
R_s	Solution gas-oil ratio.
T_a	Atmospheric temperature, (°K)
T_f	Bottomhole temperature, (°K)
T_{tf}	Flowing well head temperature, (°K)
$\bar{T}$	Mean temperature in each interval, (°K)
$\bar{v}$	Volume occupied by the fluids at flowing conditions, per barrel of oil at standard conditions, (ft^3/bbl.)
$\bar{z}$	Gas deviation factor at mean conditions for each interval
γ_f	Produced fluids mixture specific gravity
γ_g	Gas specific gravity
γ_o	Oil specific gravity
γ_w	Water specific gravity

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